International Basic and Applied Research Journal

Research Article (Subject – Petrophysics)

Optimization of Tortuosity and Cementation Factors for Coastal and Central Swamp Depobelts in the Niger Delta Oil Province

Kufre Iberedem[1], Monday Udofia Udoh[2], Francis Fusier [1], Joseph Chinye[2], David Okon Inyang[3] and Stephen Sabo Tsaku[4]

[1] Institute of Petroleum Studies, University of Port Harcourt, Nigeria.
[2]Pioneer-Alfa Petroleum Services Ltd, Benin City, Edo State, Nigeria.
[3] Geology Department, University of Calabar, Cross River State, Nigeria
[4]Reservoir Engineering Services Department, IDSL, Benin City, Edo State.

Received: 03 August 2016, Revised Received: 13 March 2017, Accepted: 17 March 2017

Abstract

This study was carried out to investigate and develop an improved tortuosity factor (**a**) and cementation exponent (**m**) for computing relatively more reliable formation resistivity factor. Fifty-two samples were collected from the Eastern Coastal Swamp I and II depobelts of the Niger Delta, while forty-five samples were collected from sites within the Eastern Coastal Swamp I and II depobelts of the Niger Delta. **a** and **m** relationships were obtained by laboratory measurements at given depths. Other relevant parameters such as R_w, R_o, and ø were determined from core analysis by saturating core plugs with brine. Non-linear regression analysis was done to generate a, m and ø from True vertical Depth measurements of each depobelts using Ms-excel window. An improved Formation Resistivity factor model was developed for the various depobelts and indeed Niger delta. Statistical error analysis was done using sum of squared deviation to check for the degree of accuracy and deviations from constant values given by various authors. Results of the analysis showed values of 1.31 and 1.72 for **a** and **m** for the Eastern Central Swamp I and II depobelt, 1.10 and 1.63 for **a** and **m** for Eastern Coastal Swamp I and II depobelt respectively and 1.38 and 1.54 for **a** and **m** for the combined depobelts in the Niger Delta. High correlation coefficient and sum of squared deviation indicate that the obtained results were accurate for effective prediction of the formation resistivity factor for Niger Delta fields.

Keywords: Optimization, Tortuosity, Cementation exponent, Water and Hydrocarbon saturations, Core, Coastal and Central Depobelts, Niger Delta.

Introduction

A reservoir rock may be defined as a formation that has the capacity to store fluid and have the ability to release the fluid when tapped as a resource (Etu–Efeotor, 1997). Such fluid can be oil, gas or water. Therefore, the exploration for oil and gas in the Niger Delta is actually, the search for hydrocarbon bearing reservoir sandstones. The exploration and

development of a reservoir requires reasonable understanding of its occurrence and morphology of the sediments. Sandstone occurs in different sedimentary environments, which is a part of the earth's surface that is physically, chemically and biologically distinct from adjacent terrains (Selley, 1985).

Tortuosity (a) and cementation exponent (m) are critical factors in the determination of water and hydrocarbon saturation using Archie's equation and for overall estimation of hydrocarbon in place. There is no direct measurement of hydrocarbon saturation for now except through the knowledge of water saturation using the simple equation $S_w + S_h + S_g = 1$, where S_w is the water saturation, S_h is the hydrocarbon saturation and S_g is the gas saturation assuming the reservoir is in three phases. Water saturation S_w in this case directly depends on these parameters under consideration, **a** and **m**. The factor **a,** describes the way the pore spaces are arranged and possibly its length and graphically defined as the intercept of a plot of Formation Resistivity Factor (FRF) against porosity (**Pickett plot**) on the FRF axis while **m** is the slope. It also corrects for variation in compaction, pore structure and grain size. Tortuosity is dependent on the salinity of the formation, surface conductance and ionic mobility, wettability and presence and distribution of conductive solid materials (Ransom, 1984). On the other hand, **m** indicates the strength of the cementing material in binding the sediments of a formation together. It is a function of depth of burial/overburden, porosity and pore geometry. The cementing material in this case may be calcite or silica cement. Both of these parameters vary with the pore geometry of rock, grain shape, compaction, depth and in general the lithology of the reservoir rock. Of all these factors mentioned, a few (pore geometry, grain shape) have been given considerations by geologist/petrophysicists in the determination of the values of **a** and **m**. These parameters are determined in the laboratory by routine core analysis or log motifs where core data is not available. This gives the generalized Archie's equation for clean sandstone formation devoid of shale:

$S_w^n = a*R_w/Ø^2*R_t$ where R_t is the true resistivity, R_w is the resistivity of the brine, Ø is the porosity , S_w is the water saturation, n is the saturation exponent and equals to 2.

From the relation, $F = a/ ø^m$

It is found that an increase in the formation factor will results in a corresponding decrease in the porosity due to the tortuosity of the pore structure which Archie regarded as 1 for rocks with high formation water salinity and less clay mineral intercalations.

Studies have shown that **m** is also a function of compaction due to overburden pressure (Fatt, 1957) and depth of burial, shape and distribution of pore geometry particularly in vuggy and fractured formations. For poorly cemented sandstone sediments, **m** is usually taken to be less than 2 and/or more than 2 when grains are well cemented. It is important to take into considerations all the above factors especially the depth of sediment burial in order to be able to give a quick and reliable estimates of **a** and **m** for effective estimation of water saturations and overall hydrocarbon in place for the Niger Delta fields. The new equation seeks to minimize uncertainties around these estimations and seeks to present optimize already existing equations on these parameters especially for the Niger Delta sandstone formations.

From the Table 1 below, only formations with 100% water saturation were investigated. For other formations, the formation true resistivity (R_t) was determined from the deep induction log. The resistivity of the formation water was calculated using the spontaneous potential (SP) log with known values for mud filtrate resistivity (Porter and Carothers, 1970).

Table 1. FRF correlations developed by some authors IFP training manual, 2014.

Type of Formation	Formation Resistivity Factor
Humble's formula for granular or soft sandstones	$F = \frac{0.62}{\Phi^{2.15}}$
Tixier formula for soft sandstone formation	$F = \frac{0.81}{\Phi^{2}}$
Archie formula for Compacted formation (Average to good porosity)	$F = \frac{1}{\Phi^{2}}$
Shell formula for low porosity, not fractured, carbonates	$F = \frac{1}{\Phi^{1.87+\frac{0.019}{\Phi}}}$

Objective

To develop a more reliable relationship between measured and calculated values of the formation resistivity factor for sediments of the depobelts of the Niger Delta oil province.

Geologic Setting and Stratigraphy of the Niger Delta

Niger Delta province is found in the Gulf of Guinea and lies between latitude 3^0 and 6^0N of the equator and longitude 5^0 and 8^0 E of the Greenwich meridian. It was formed at a rift triple junction related to the opening of the South Atlantic in the late Jurassic and continuing into the cretaceous (Tuttle et al., 1999). It has a sediment thickness of about 12km and contains one petroleum system identified as the tertiary Niger Delta (Akata-Agbada) petroleum system (Kulke, 1995, Ekweozor and Daukoru, 1994). The Niger Delta sediment is composed of three diachronous siliciastic units: the deep marine pro-delta Akata Formation, the shallow marine delta front Agbada Formation continental delta top Benin Formation (Reijers, 2011). The Agbada Formation is the main host of hydrocarbons in the Niger Delta while the Benin Formation consists predominantly of continental, fluvial, continuous sheets of sand. The Niger Delta province is characterized by growth faults and their associated structures (Roll over anticlines) and these structures are well developed in the Agbada Formation. These structures are dying out within the shales of the Akata formation. There are some diapiric structures mainly of mud/shale materials. These however, create large-scale regional faults in the area. Offshore, seismic data have shown large sedimentary sequences and shale, tectonics and structures and these forms excellent petroleum traps and have large oil pools in the deep offshore of the Niger Delta. The region is also characterized by fracture zones manifested in the forms of ridges and trenches. These fracture zones are believed to have developed in the cretaceous and ~~it~~ ridges subdivid~~ed~~ the margin into individual basins and in Nigeria form the boundary faults of the cretaceous Benue – Abakaliki Trough which cuts far into the West African shield. The Niger Delta region further consists of depositional belts or centers which ranges from 30 – 60km in width, prograding southward over oceanic crust into the Gulf of Guinea (Stacher, 1995). Each depobelt is a separate unit that corresponds to a break in regional of the delta and is bounded landward by growth faults and seaward by large counter regional faults of the next seaward belt (Evamy et al., 1978). Five major depobelts have been identified which are: Northern Delta, Central Delta, Greater Ughelli, Coastal and Distal Swamps respectively. The last depobelt has been further divided into deep and shallow offshore depobelts by modern authors (Fig. 1).

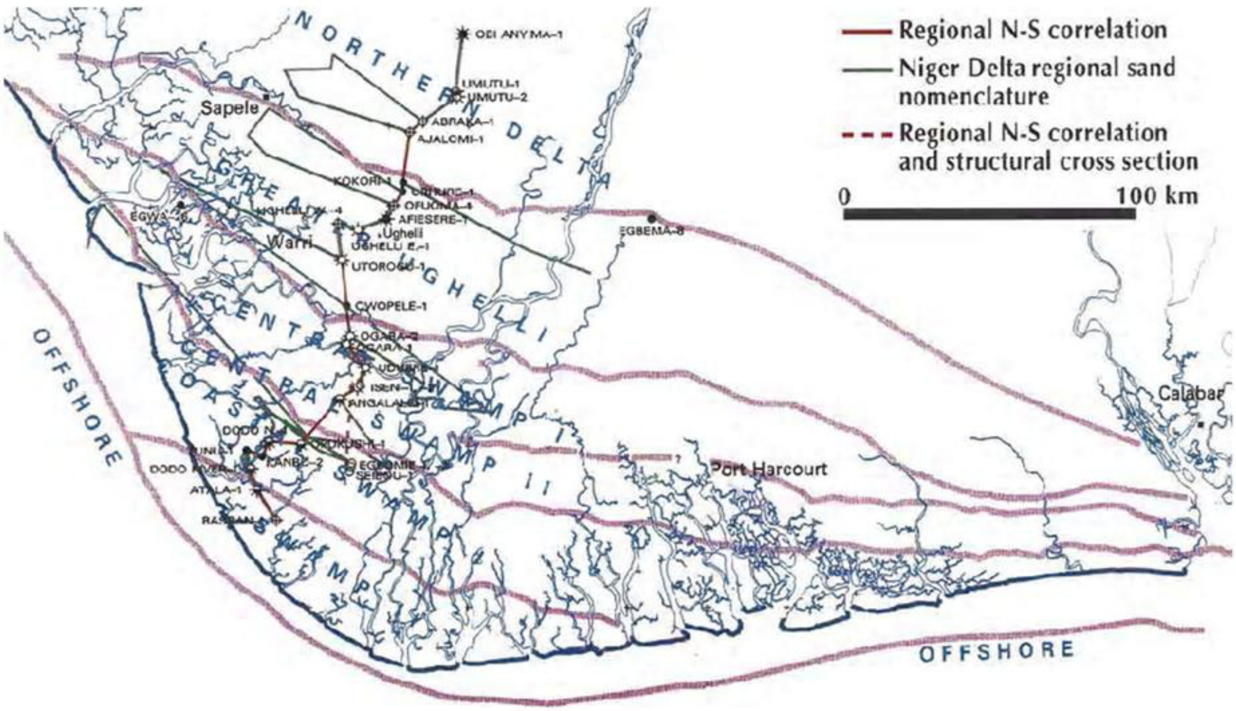

Fig. 1. Depobelt map of the Niger Delta oil province (After Reijers, 2011).

Bulk Volume Determination

The bulk volume was calculated by taking the difference between two weights divided by the density of the fluid with which the core was saturated and or immersed. Archimedes' principle was used in the displacement of the fluid. Core sample was first saturated with water (since it is easily vaporized from core sample) and then weighed. It is then submerged in the saturating fluid, and its submerged weight is noted down. Two weights were taken: that of the vessel and water before the core sample was submerged, and that of the vessel, water, and sample after immersion. The weight difference between the weight of core sample saturated with water and the submerged weight equals the weight of the water displaced by the core sample.

Pore volume/Grain volume determination

The experiment was performed in laboratory (Fig. 2) by loading core samples in a hydrostatic core holder and porosimeter respectively with applied pressure. Amount of gas injected was recorded and Boyle's law was applied to determine the grain/ pore volume.

Fig. 2. Pore/grain volume determination at Ansett Integrated Services, Port Harcourt.

Determination of *m*, *a* and Ø

Hence, **a** and **m** were determined from the relation: F =a ϕ^{-m}

Then, **a** =F/ ϕ^{-m}, and a log relationship was established for the above equation to generate **m** as follows: **m** = logF/log ø. Alternatively, it was determined from a plot of F against ø, where **a** was the intercept and **m** the slope of the plot. However, porosity was obtained from the relation, Ø = Bulk Vol- Grain Vol /Bulk vol. x 100.

Determination of R_W and R_O

Both of these parameters were obtained from conventional core analysis methods and (Patrick, 2006) best explains the process. The samples were initially saturated with brine, loaded into test cells (with water-wet porous plates) and the net confining stress is applied. Each sample was flushed with a sufficient volume of synthetic formation brine to establish rock/brine equilibrium and each sample was 100% saturated with brine. Usually this translates into a minimum of 20 to 40 pore volumes of brine being injected through a sample under backpressure conditions. Independent assessment was done to ensure that all remaining gases are removed from a sample's pore volume. A practical check was to vary the pore pressure and monitor the resistance response. As this check was conducted, the temperature was carefully assessed and the net confining stress was checked to remain constant.

Formation Resistivity Factor determination

Formation resistivity factor (F) was calculated as follows:

$F = R_0/R_w = \phi^{-m}$

Or m = -Log F/Log ø, taking 'a' to be 1

Where:

F = Formation Resistivity Factor

R_0 = Resistivity of 100% saturated plug sample in Ωm

R_w = Resistivity of saturated brine in Ωm

a = Intercept on the F - ϕ cross plot

m = Cementation exponent

ø = Porosity, fraction.

Results and Discussion

The following parameters as used in Appendix A give a summary of core data in Depth(ft), TVDSS, Porosity, ϕ and Formation Resistivity Factor model developed for the eastern depobelt of the Coastal and Central I and II Niger Delta province. These were computed using the convectional technique, which uses the log-log plot of the formation resistivity factor and the porosity of the formation (Fig. 3-10). The plots showing the relationship between the formation resistivity factor and the porosity values for the different depobelts have been provided below,**a** and **m** parameters were determined from the respective plots as shown below.

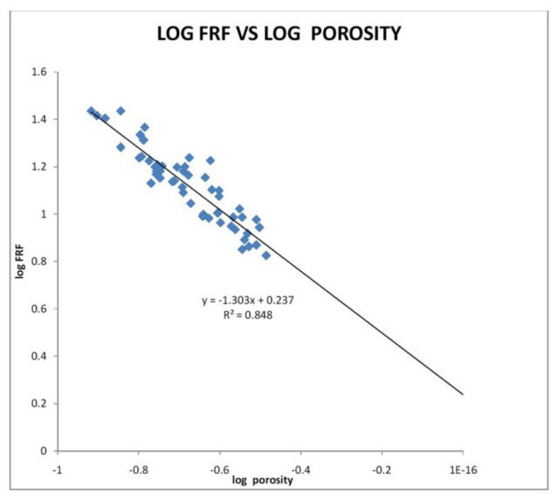

Fig. 3. Log plot of FRF and Porosity shows that higher log FRF values have relatively lower log porosity. Thus indicates an inverse relationship between log FRF and log porosity. The coefficient of determination is 0.8481 which indicates relatively high correlativity and predictivity between FRF and porosity.

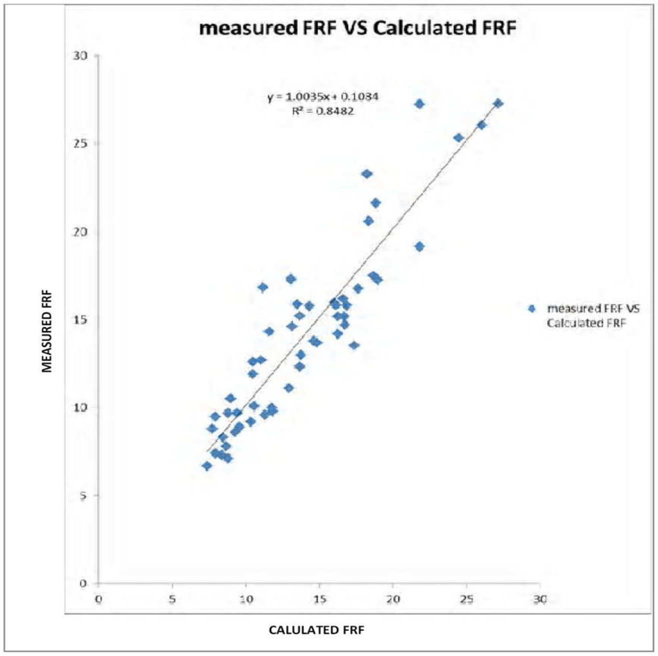

Fig. 4. The Plot of the measured Formation Resistivity Factor and calculated Formation Resistivity Factor for Eastern Central Swamp Depobelt of the Niger Delta. The coefficient of determination between measured FRF and calculated FRF is 0.8482. The plot between measured FRF and calculated FRF shows high correlativity.

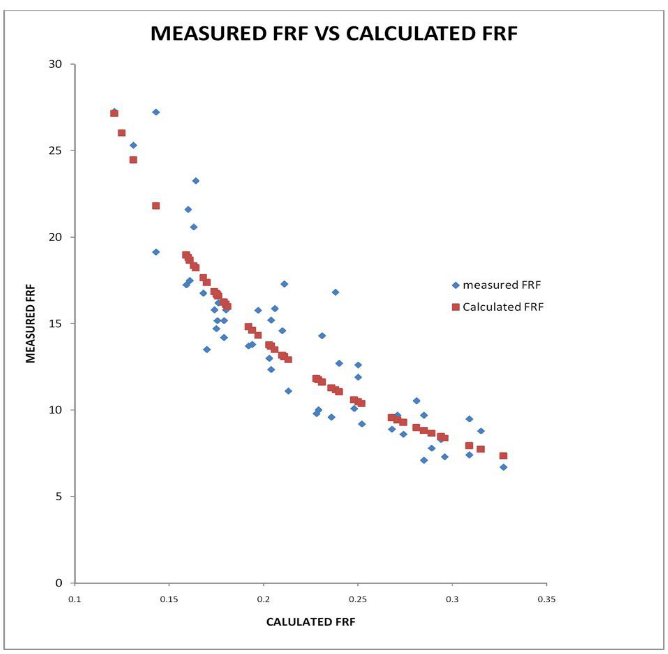

Fig. 5. The plot of measured versus calculated Formation Resistivity factor for the Eastern depobelt of the Niger delta. The plot between measured FRF and calculated FRF for the Eastern depobelt of the Niger delta shows high correlativity.

Analysis of Results

The above stated plots were obtained from the information gathered during the experimental analysis of the core samples from different location and based on their respective depths. Fifty-two samples were collected from the Eastern Central Swamp I and II depobelts, while forty-five samples were collected from sites within the Eastern Coastal Swamp I and II depobelts of the Niger delta.

Eastern Central I and II Depobelts

Figure 3 shows the Log-log plot of the formation resistivity factor and porosity based on the plot, it was observed that the intercept (a) and slope (m) for the region were deduced to be 1.31 and 1.72 from the non-linear regression analysis carried out. The coefficient of correlation was observed to be 84.81% effective. Similarly, figure 4 plot measured against calculated formation resistivity factor value displayed a correlation coefficient of 84.82%, however, a similar trend of measured versus calculated value was also observed in figure 5 for the same Eastern Central I and II depobelts region.

Eastern Coastal Swamp I and II Depobelts

Figure 6 showed the log-log plot of the formation resistivity and the porosity values, the intercept (**a**) and slope (**m**) values were computed from the plot as 1.10 and 1.6379. The coefficient of correlation for this region has showed 95.06%. The relationship between the measured and calculated formation resistivity factor values was observed to be 95.06% as observed in figure 7. Conversely, the formation resistivity factor showed a decrease with increase in porosity values and vice visa for the region, with a similar trend with figure 7.

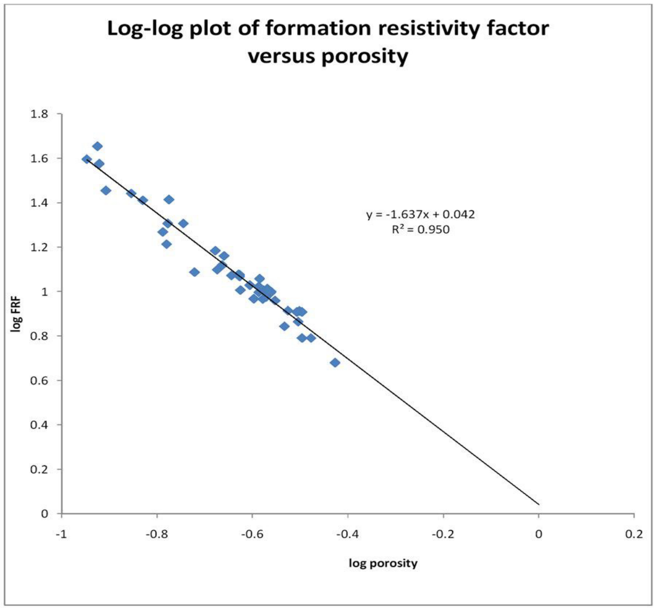

Fig. 6. The Log-log plot of Formation Resistivity factor versus the Porosity value for the Coastal Swamp depobelt of the Niger delta. Log plot of FRF and Porosity shows that higher log FRF values have relatively lower log porosity. Thus indicates an inverse relationship between log FRF and log porosity. The coefficient of determination is 0.950 which indicates relatively higher inverse correlativity and predictivity between FRF and porosity.

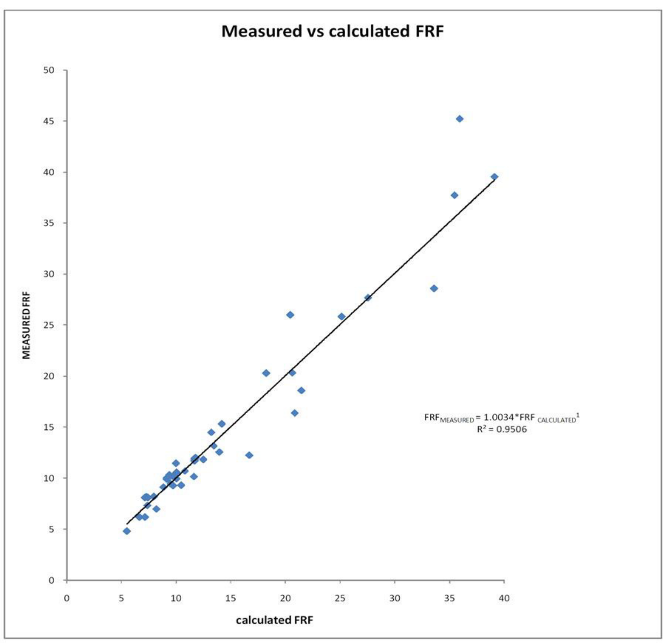

Fig. 7. The plot of measured Formation Resistivity and the calculated Formation Resistivity factor for the Eastern Coastal Swamp of the Niger delta. The coefficient of determination between measured FRF and calculated FRF is 0.9506.The plot between measured FRF and calculated FRF shows high correlativity.

Eastern Central and Coastal Swamp I and II Depobelts

After considering **a** and **m** parameters for each of the depobelts, it has been imperative to compute and optimally determine the tortuosity and cementation value for the entire Eastern Central and Coastal Swamp depobelts. The log-log plot shown in figure 8 for the formation resistivity factor and porosity generated showed different unique parameters for the region. Parameters **a** and **m** were computed to be 1.38 and 1.54 for the region (Eastern Central and Coastal depobelts). These values hold good for the region as it is reflected by a better trend of the measured against calculated values.

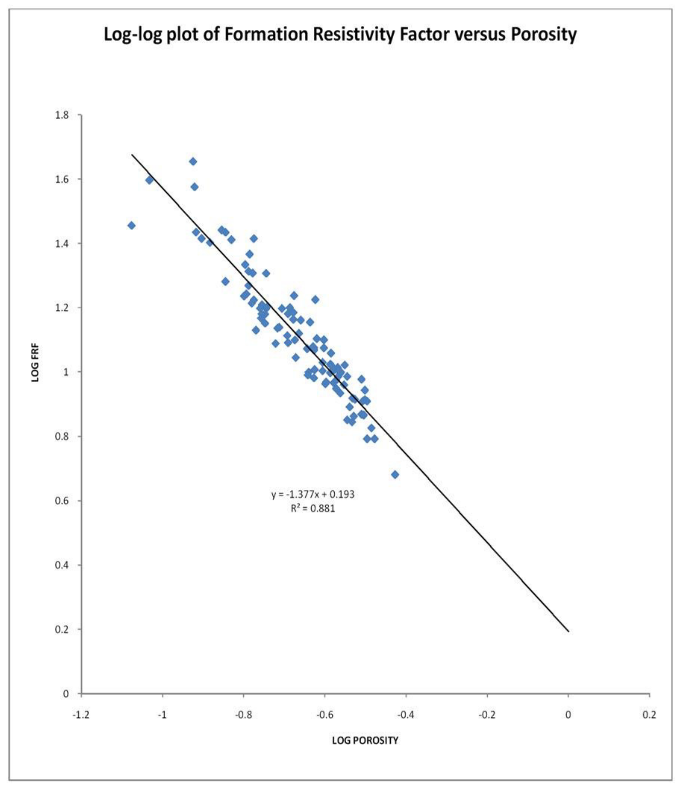

Fig. 8. Showing the log –log plot of formation resistivity factor versus porosity for the combined Eastern Central and Coastal Swamp depobelt of the Niger delta. Log plot of FRF and Porosity shows that higher log FRF values have relatively lower log porosity. Thus indicates an inverse relationship between log FRF and log porosity. The coefficient of determination is 0.881 which indicates relatively higher inverse correlativity and predictivity between FRF and porosity.

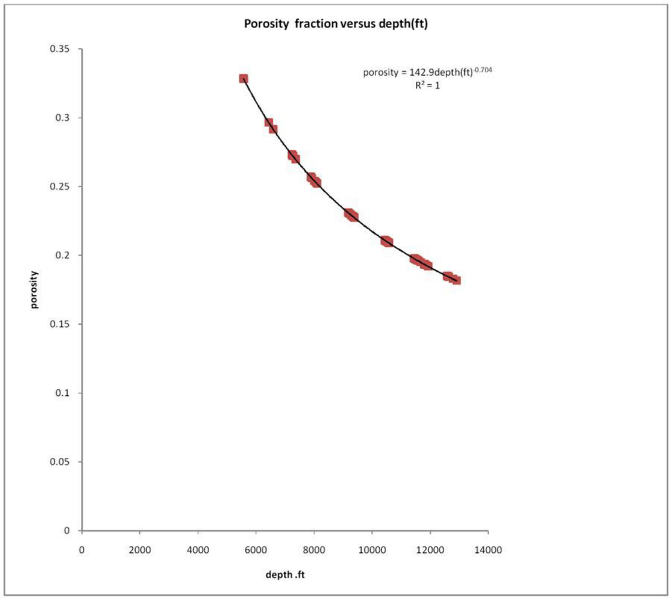

Fig. 9. Showing the non-linear regression plot for the relationship between porosity and depth for the Eastern Central and Coastal Swamp depobelts for the Niger Delta. The plot of porosity and depth shows that up to a certain depth porosity decreases with depth and after certain depth the decrease in porosity is not linear.

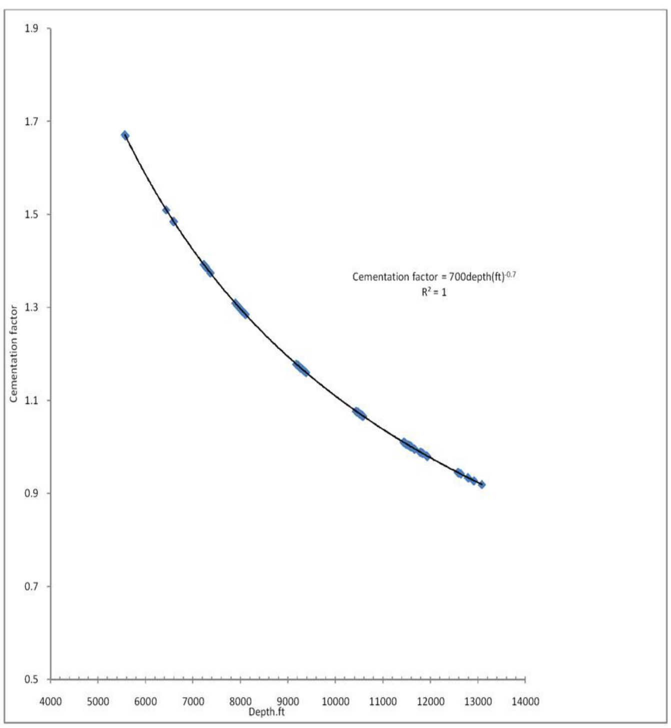

Fig. 10. The variation of the cementing factor with depth for the Eastern Central and Coastal depobelts for the Niger Delta. The plot of cementation factor and depth shows that cementation factor decreases with depth but this relationship is not linear.

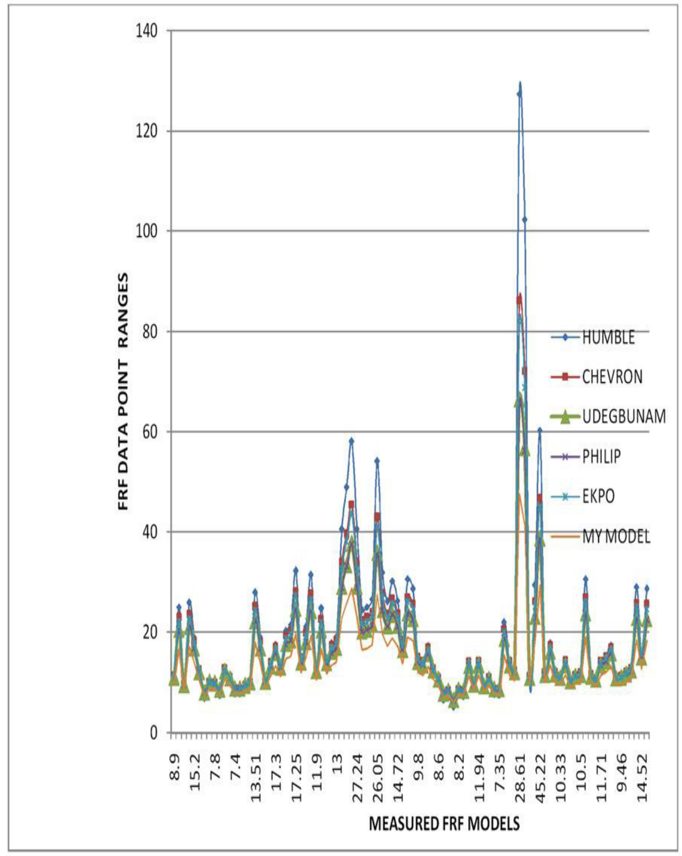

Fig. 11. Compared model used in this study in relation to other model.

A plot of depth variation vs. porosity was generated in order to study its trend using the linear and non-linear approaches. The non-linear regression proved to be excellent as observed in figure 9, which shows porosity decreases with depth and is mainly due to effect of the overburden. Figure 10 shows the variation of the cementation factor for the entire Eastern Central and Coastal Swamp depobelts using the non-linear regression tool. It was observed that the cementation factor decreases with increase in depth depicting a level of unconsolidation of the sand sediments due to under compaction, abnormal pressures and other associated factors. However, figure 11 and table 2 below shows comparative models used in computing the formation resistivity factor validation in the Niger Delta.

Table 2. Other models used in computing formation resistivity factor with respect to model formulated in this study for validation and testing. Models used include the following for comparison.

Author's Name	No of core samples	Tortuosity factor '*a*'	cementation exponent, '*m*'	Model
Archie	165	1	1.3	$F = 1/\phi^{1.3}$
Humble	30	0.62	2.15	$F = 0.62/\phi^{2.15}$
Chevron	1833	1.13	1.73	$F = 1.13/\phi^{1.73}$
Udegbunam and Ndukwe	80+	1.43	1.55	$F=1.43\phi^{1.55}$
Phillips	793	1.45	1.54	$F = 1.45/\phi^{1.54}$
Formulated model	97	1.38	1.54	$F = 1.38/\phi^{1.54}$

Conclusions

An efficient correlation has been established for estimating the cementation factor and porosity values in relation to the depth for the Eastern Central and Coastal depobelts of the Niger Delta oil province as $F=1.38/Ø^{1.54}$. This improved model is very effective for quick look estimations of water saturation within the depobelts of study area of Niger Delta oil province as shown by their high correlation coefficient and sum of squared deviation. The study has also demonstrated that the Archie's parameter for quick look is likely to be erroneous for water and hydrocarbon saturation for the depobelts under study because of high deviations of Archie's formation resistivity factor model with the Formulated formation resistivity factor model by over forty percent as shown in Appendix 1.

From this study some generalized conclusions can be drawn which are given below. However for applying, all generalizations, in other basins of other regions careful evaluation and validation are recommended.

1. There is an inverse relationship between formation resistivity factor and porosity. Higher formation resistivity factor have relatively lower porosity and lower formation resistivity have relatively higher porosity.

2. The plot of relationship between porosity and depth shows that up to a certain depth porosity decreases. However after certain depth the decrease in porosity is not linear.

3. The plot of relationship between cementation factor and depth shows that cementation factor decreases with depth but this relationship is not linear.

Acknowledgement

The authors are very grateful to the Centre for Petroleum Geosciences, University of Port Harcourt, Rivers State, Nigeria for the provision of the data used in this work and a good atmosphere to carry out this study. Authors are thankful to reviewers for their constructive and useful comments and suggestions leading to improved manuscript.

Appendix 1

Results showing the measured values for the depth, porosity and formation resistivity factor for the Eastern Central and Coastal depobelt I and II, Niger Delta.

DEPTH (TVD-SS.ft)	Porosity	FRF	Log PHI	Log FRF	Model FRF (This work)	Archie
6434	0.268	8.9	-0.57187	0.94939	9.600605	13.92292
6593	0.179	14.2	-0.74715	1.152288	16.75666	31.21001
6592	0.294	8.3	-0.53165	0.919078	8.448999	11.56925
6595	0.176	16.2	-0.75449	1.209515	17.15209	32.28306
6595	0.204	15.2	-0.69037	1.181844	13.99056	24.02922
7226	0.252	9.2	-0.5986	0.963788	10.45182	15.74704
7229	0.327	6.7	-0.48545	0.826075	7.295393	9.352
7231	0.285	9.7	-0.54516	0.986772	8.819393	12.31148
7238	0.289	7.8	-0.5391	0.892095	8.651384	11.97304
7244	0.315	8.8	-0.50169	0.944483	7.681677	10.07811
7260	0.25	12.6	-0.60206	1.100371	10.56738	16
7262	0.271	9.7	-0.56703	0.986772	9.454248	13.61637
7364	0.309	7.4	-0.51004	0.869232	7.888272	10.47329
7266	0.309	9.5	-0.51004	0.977724	7.888272	10.47329
7271	0.296	7.3	-0.52871	0.863323	8.37032	11.41344
7276	0.285	7.1	-0.54516	0.851258	8.819393	12.31148
9173.46	0.17	13.51	-0.76955	1.130655	17.99306	34.60208
9207.34	0.204	12.35	-0.69037	1.091667	13.99056	24.02922
9215.82	0.281	10.53	-0.55129	1.022428	8.993109	12.66448
9226.83	0.238	16.82	-0.62342	1.225826	11.30963	17.65412
9274.28	0.211	17.3	-0.67572	1.238046	13.35411	22.46131
9343.77	0.24	12.71	-0.61979	1.104146	11.17978	17.36111
9347.16	0.197	15.78	-0.70553	1.198107	14.68119	25.76722
9358.18	0.192	13.7	-0.7167	1.136721	15.21139	27.12674
9380.21	0.159	17.25	-0.7986	1.236789	19.73316	39.5554
10531.7	0.229	10	-0.64016	1	11.92756	19.06905
10538.6	0.194	13.8	-0.7122	1.139879	14.99541	26.57031
10543.6	0.161	17.5	-0.79317	1.243038	19.39567	38.57876
10550.6	0.25	11.9	-0.60206	1.075547	10.56738	16
10557.7	0.18	15.8	-0.74473	1.198657	16.62833	30.8642
10559.7	0.231	14.3	-0.63639	1.155336	11.78528	18.74028
10564.7	0.21	14.6	-0.67778	1.164353	13.44194	22.67574
10570.7	0.203	13	-0.6925	1.113943	14.08575	24.26654
11433.32	0.143	19.142	-0.84466	1.281987	22.84341	48.90215
11447.19	0.131	25.31	-0.88273	1.403292	25.78043	58.27166
11451.21	0.121	27.26	-0.91721	1.435526	28.76609	68.30135
11462.85	0.143	27.24	-0.84466	1.435207	22.84341	48.90215
11470.91	0.181	15.97	-0.74232	1.203305	16.50168	30.5241
11488.8	0.179	15.17	-0.74715	1.180986	16.75666	31.21001
11511.61	0.174	15.8	-0.75945	1.198657	17.42475	33.02946
11529.03	0.125	26.05	-0.90309	1.415808	27.50355	64
11551.35	0.16	21.61	-0.79588	1.334655	19.56316	39.0625
11565.61	0.1755	15.18	-0.75572	1.181272	17.21956	32.46727
11574.52	0.164	23.27	-0.78516	1.366796	18.90776	37.18025
11586.99	0.175	14.72	-0.75696	1.167908	17.2875	32.65306
11595.9	0.206	15.88	-0.68613	1.20085	13.80346	23.5649
11597.67	0.163	20.59	-0.78781	1.313656	19.06802	37.63785

11666.11	0.168	16.77	-0.77469	1.224533	18.28933	35.43084
11782.7	0.228	9.8	-0.64207	0.991226	11.99981	19.23669
11803.5	0.236	9.6	-0.62709	0.982271	11.44211	17.95461
11833.4	0.213	11.1	-0.67162	1.045323	13.18138	22.04148
11914.2	0.248	10.1	-0.60555	1.004321	10.68517	16.25911
11933.4	0.274	8.6	-0.56225	0.934498	9.311697	13.31984
5564	0.333	6.2	-0.47756	0.792392	7.114617	9.018027
5575.3	0.319	6.2	-0.49621	0.792392	7.54907	9.826947
5579.6	0.374	4.8	-0.42713	0.681241	6.061244	7.149189
7887	0.315	8.2	-0.50169	0.913814	7.681677	10.07811
7900.5	0.319	8.12	-0.49621	0.909556	7.54907	9.826947
7924.7	0.237	10.19	-0.62525	1.008174	11.37554	17.80341
8003.5	0.293	7	-0.53313	0.845098	8.488819	11.64836
8009.7	0.236	11.94	-0.62709	1.077004	11.44211	17.95461
8047.5	0.298	8.23	-0.52578	0.9154	8.292895	11.26075
8085.8	0.274	9.91	-0.56225	0.996074	9.311697	13.31984
8090.5	0.311	8.12	-0.50724	0.909556	7.818353	10.33902
8102.5	0.313	7.35	-0.50446	0.866287	7.749495	10.20731
9224.1	0.19	12.27	-0.72125	1.088845	15.4328	27.70083
9226.1	0.236	11.81	-0.62709	1.07225	11.44211	17.95461
9242.9	0.253	9.32	-0.59688	0.969416	10.39485	15.6228
9256.1	0.084	28.61	-1.07572	1.456518	47.60134	141.7234
9276.9	0.093	39.55	-1.03152	1.597146	41.36358	115.6203
9304.7	0.27	10.31	-0.56864	1.013259	9.502603	13.71742
9332.5	0.166	16.39	-0.77989	1.214579	18.59411	36.28974
10430.7	0.119	45.22	-0.92445	1.655331	29.43539	70.61648
10439.1	0.26	11.46	-0.58503	1.059185	10.01063	14.7929
10440.1	0.21	15.32	-0.67778	1.185259	13.44194	22.67574
10445.1	0.259	10.59	-0.5867	1.024896	10.06401	14.90735
10451.7	0.27	10.33	-0.56864	1.0141	9.502603	13.71742
10456.2	0.235	12	-0.62893	1.079181	11.50935	18.10774
10458.7	0.28	9.14	-0.55284	0.960946	9.037463	12.7551
10464.4	0.265	10.19	-0.57675	1.008174	9.750913	14.23994
10472	0.26	10.5	-0.58503	1.021189	10.01063	14.7929
10482.9	0.163	18.6	-0.78781	1.269513	19.06802	37.63785
10493.4	0.264	9.28	-0.5784	0.967548	9.801921	14.34803
10501.4	0.275	10.01	-0.56067	1.000434	9.265001	13.22314
10505.6	0.236	11.71	-0.62709	1.068557	11.44211	17.95461
10508.1	0.227	11.84	-0.64397	1.073352	12.07283	19.40655
10513.1	0.212	12.59	-0.67366	1.100026	13.26726	22.24991
10564.7	0.271	10.15	-0.56703	1.006466	9.454248	13.61637
10567.2	0.268	9.46	-0.57187	0.975891	9.600605	13.92292
10574.1	0.259	9.96	-0.5867	0.998259	10.06401	14.90735
10576.1	0.248	10.73	-0.60555	1.0306	10.68517	16.25911
12572.2	0.167	20.33	-0.77728	1.308137	18.44063	35.85643
12605.06	0.219	14.52	-0.65956	1.161967	12.68562	20.85027
12636.08	0.168	26.03	-0.77469	1.415474	18.28933	35.43084
12783.17	0.148	25.84	-0.82974	1.412293	21.78529	45.65376
12796.02	0.217	13.19	-0.66354	1.120245	12.84725	21.23638
12909.8	0.12	37.73	-0.92082	1.576687	29.09742	69.44444
12911.67	0.14	27.7	-0.85387	1.44248	23.52166	51.02041
13082.13	0.18	20.3	-0.74473	1.307496	16.62833	30.8642

References

Archie, G. E. 1942. The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics. AIME., 146 (1), 54-57.

Ekweozor, C. M., and Daukoru, E. M. 1994. Northern Delta depobelt portion of the Akata-Agbada Petroleum system, Niger Delta, Nigeria. AAPG Memoir 60: Tulsa, American Association of Petroleum Geologists, 605-610.

Etu-Efeotor J. O. 1997. Fundamental of Petroleum Geology. Paragraphics/lecture notes, Port Harcourt. 1-62.

Evamy, B.D., Haremboure, J., Kamerling, P., Knaap, W.A., Molloy, F.A., and Rowlands, P.H. 1978. Hydrocarbon habitat of Tertiary Niger Delta. American Association of Petroleum Geologists Bulletin, 62 (26), 295.

Fatt, I. 1957. Effect of Overburden and Reservoir Pressure on Electrical Logging Formation Factor. Bulletin AAPG, 41.58 (2), 346- 351.

IFP training lecture notes. 2014. Well logging and Interpretation. 1-56.

Kulke, H. 1995. Regional Petroleum Geology of the World. Part II: Africa, America, Australia and Antarctica: Berlin Gebrüder Borntraeger, 140-170.

Patrick M. L. 2006. Core Analysis for Electrical Properties. Petrophysics, 47 (3), 191–213.

Porter, C.R. and Carothers, J. W. 1970. Formation Factor- Porosity Relation Derived from Well Log Data. Trans., SPWLA Paper A.

Ransom, R.C. 1984. A Contribution toward a Better Understanding of the Modified Archie Formation Resistivity Factor Relationship. The Log Analyst, 7-12.

Reijers, T. J. 2011. Stratigraphy and Sedimentology of the Niger Delta. Geologos, Geo-Training & Travel, Gevelakkers 11, 9465 TV Anderen, The Netherlands, 17 (3), 133–162.

Selley, R. C. 1985. Ancient Sedimentary Environment. Third edition, Cornell University Press, Ithaca, NY, 317.

Stacher, P. 1995. Present understanding of the Niger Delta hydrocarbon habitat,In, Oti, M.N., and Postma, G., eds., Geology of Deltas: Rotterdam, A. A. Balkema.

Tuttle, M. L. W., Charpentier, R.R., and Brownfield, M.E. 1999. The Niger delta petroleum system: Niger delta province, Nigeria, Cameroon, and Equatorial Guinea, Africa. USGS Open-file report 99-50-H.

Cite this article: Iberedem, K., Udoh, M.U., Fusier, F., Chinye, J., Inyang, D.O., and Tsaku, S.S. 2017. Optimization of Tortuosity and Cementation Factors for Coastal and Central Swamp Depobelts in the Niger Delta Oil Province. International Basic and Applied Research Journal, Volume 03, Number 04, pp. 1-12.

